

3.1 Stationary Gas Turbines For Electricity Generation

3.1.1 General¹

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are used in a broad scope of applications including electric power generators, and in various process industries. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to over 268,000 hp, with an average size of 40,200 hp.² Gas turbines greater than 4,021 hp that are used in electrical generation are used for continuous, peaking, or standby power. The primary fuels used are natural gas and distillate (No. 2) fuel oil.³

3.1.2 Process Description¹

Gas turbines comprise three major components: compressor, combustor, and power turbine. Ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that rings the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate can-shaped chambers rather than a single continuous chamber. A silo combustor has one or more chambers mounted external to the gas turbine body.²

Hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. Energy from the hot, expanding exhaust gases are then recovered in the form of shaft horsepower, of which more than 50 percent is needed to drive the internal compressor and the balance of recovered shaft energy is available to drive the external load unit.²

The heat content of the gases exiting the turbine can either be discarded without heat recovery (simple cycle); used with a heat exchanger to preheat combustion air entering the combustor can (regenerative cycle); used with or without supplementary firing, in a heat recovery steam generator to raise process steam (cogeneration); or used with or without supplementary firing to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).

Gas turbines may have one, two, or three shafts to transmit power from the inlet air compression turbine, the power turbine, and the exhaust turbine. Of the four basic turbine operating cycles (simple, regenerative, cogeneration, and combined cycles), three configurations (1, 2, or 3 shaft), and three types of combustors (annular, can-annular, and silo) for gas turbines, the majority of gas turbines used in large stationary installations are either peaking simple cycle two-shaft or base load combined cycle gas turbines.

If the heat recovery steam generator (HRSG) is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal unit [lb/MMBtu]) will apply to cogeneration/combined cycle systems. The output-specific emissions (pounds per horsepower-hour [lb/hp-hr]) will decrease according to the ratio of simple cycle to combined cycle power output. If the HRSG is supplementary fired, the emissions and fuel usage must be considered to estimate stack emissions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NO_x) and carbon monoxide (CO). To a lesser extent, hydrocarbons (HC) and other organic compounds, and particulate matter (PM), which includes both visible (smoke) and nonvisible emissions are also emitted. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Smoke, CO, and HC, are primarily the result of incomplete combustion. Ash and metallic additives in the fuel may also contribute to the particulate loading in the exhaust. Oxides of sulfur (SO_x) will only appear in a significant quantity if heavy oils are fired in the turbine. Emissions of sulfur compounds, mainly sulfur dioxide (SO_2), are directly related to the sulfur content of the fuel.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by two fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel is thermal NO_x , which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface. A component of thermal NO_x , called prompt NO_x , is formed from early reactions of nitrogen intermediaries and hydrocarbon radicals from the fuel. The prompt NO_x forms within the flame and is usually negligible compared to the amount of thermal NO_x formed. The second mechanism, fuel NO_x , stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NO_x formed is thermal NO_x . Distillate oils have low levels of fuel-bound nitrogen. These levels usually are significant only for high degrees of NO_x controls where thermal NO_x has been suppressed to the level where fuel NO_x is significant.

The maximum thermal NO_x production occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_x . The thermal NO_x generation also decreases rapidly as the temperature drops below the adiabatic temperature (for a given stoichiometry). Maximum reduction of thermal NO_x generation can thus be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place in the can downstream of the primary flame, so that the high excess air levels are not indicative of the NO_x forming potential. The combustion in conventional can designs is by diffusion flames which are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and the majority of NO_x is formed. Since the localized NO_x forming regions are at much higher temperatures than the adiabatic flame temperature for the overall mixture, the rate of NO_x formation is dependent on the fuel/air mixing process. The mixing determines the prevalence of the high temperature regions as well as the peak temperature attained. Also, operation at full loads gives higher temperatures in the peak NO_x forming regions. Newer model gas turbines use lean, pre-mixed combustion resulting in lower flame (hot spot) temperature and lower NO_x .

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure.⁴ Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone through the sensible heat and, if condensation occurs during compression, the latent heat of vaporization. For a given fuel firing rate, lower ambient temperatures lower the peak flame temperature, lowering NO_x significantly. Lower barometric pressure will also lower the temperature exiting the compressor turbine which will lower NO_x .

3.1.3.2 Carbon Monoxide and Total Organic Compounds (Hydrocarbons) -

Carbon monoxide and HC emissions both result from incomplete combustion. Carbon monoxide results when there is insufficient residence time at high temperature to complete the final step in HC oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most HC oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching in the can by the dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. In gas turbines, CO emissions are usually higher when the unit is run at low loads.

The pollutants commonly classified as HCs can encompass a wide spectrum of volatile and semi-volatile organic compounds. They are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolyzed organic emissions.

3.1.3.3 Particulate Matter -

Particulate emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. Particulate are typically nondetectable with natural gas firing and marginally detectable with conventional sampling systems with distillate oil firing because of the low ash content. Particulate may also be formed from agglomerated soot particles, particularly from liquid fuel firing.

3.1.3.4 Greenhouse Gases - ⁵⁻¹¹

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process (typically 99.5 percent for gas and 99 percent for distillate oil). This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent).

Methane emissions vary with the fuel, combustion temperature, and firing configuration, but are highest during periods of incomplete combustion or low-temperature combustion, such as during the start-up or shut-down cycle. Typically, conditions that favor formation of N_2O also favor emissions of CH_4 .

3.1.4 Control Technologies¹²

There are three generic types of emission controls in use for gas turbines; wet controls using steam or water injection to reduce combustion temperatures for NO_x control; dry controls using advanced combustor design to suppress NO_x formation and/or promote CO burnout; and post-combustion catalytic control to selectively reduce NO_x and/or oxidize CO formed in the turbine.

3.1.4.1 Water Injection -

Water or steam injection is a mature technology that has been demonstrated as very effective in suppressing NO_x emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce the adiabatic flame temperature and the peak flame temperature in the NO_x forming regions. With water injection, there is additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one. Depending on the initial NO_x levels, such rates of injection may reduce NO_x by 60 percent or higher. Wet injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The power increase results because fuel flow is increased to maintain turbine inlet temperature at manufacturer's specifications. Both CO and HC emissions are increased by large rates of water injection.

3.1.4.2 Dry Controls -

Since thermal NO_x is a function of both temperature (exponentially) and time (linearly), the bases of dry controls are to either lower the combustor temperature using lean mixtures of air and fuel and/or staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_x emissions such as; lean combustion; reduced combustor residence time; two stage lean/lean combustion; or two stage rich/lean combustion.

Most gas turbine combustors were originally designed to operate with a stoichiometric mixture (theoretical amount of air required to react with the fuel). Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperature within the combustor will be less than that of the stoichiometric mixture. A lean mixture of air and fuel can be premixed before ignition, a stoichiometric mixture can be ignited and additional air can be introduced at a later stage (staging) creating an overall lean mixture in the turbine, or a combination of both can occur. Introducing excess air at a later stage not only creates a leaner mixture but it also can reduce the residence time of the combustor, given enough excess air is added at the later stage to create a mixture so lean that it will no longer combust. The residence time of a combustor can also be decreased by increasing the turbulence within the combustor.

Two-stage lean/lean combustors are essentially fuel-staged combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture and a stable flame that should not "blow off" or extinguish. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The high NO_x emissions associated with the higher temperature pilot flame is minor side effect compared to the desirable low NO_x emissions generated by the extremely lean mixture.

Two stage rich/lean combustors are essentially air-staged combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture will produce lower temperatures (compared to stoichiometric) and higher concentrations of CO and H₂ because of

incomplete combustion. The rich mixture decreases the amount of oxygen available for NO_x generation and the increased CO and H_2 concentrations help to reduce some of the NO_x formed. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The combustion of the lean mixture is then completed in the secondary zone.

3.1.4.3 Selective Catalytic Reduction Systems -

Selective catalytic reduction systems selectively reduce NO_x emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3 , and O_2 react on the surface of the catalyst to form N_2 and H_2O . The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 450 to 850°F) in order for the SCR system to operate properly. The range is dictated by the catalyst, typically made from noble metals, base metal oxides such as vanadium and titanium, or zeolite-based material. Exhaust gas temperatures greater than the upper limit (850°F) will cause NO_x and NH_3 to pass through the catalyst unreacted. Ammonia emissions, called NH_3 slip, may be a consideration when specifying a SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although a SCR system can operate alone, it is typically used in conjunction with water/steam injection systems to reduce NO_x emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems).

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_x , O_2 , and NH_3 , to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations are incorporating CO catalytic oxidation modules along with the NO_x reduction catalyst for simultaneous CO/ NO_x control.

The average gaseous emission factors for uncontrolled gas turbines (firing natural gas and fuel oil) are presented in Table 3.1-1. There is some variation in emissions over the population of large uncontrolled gas turbines because of the diversity of engine designs, sizes, and models. Table 3.1-2 presents emission factors for gas turbines controlled with water injection, steam injection, and selective catalytic reduction. Emission factors for fuel oil-fired turbines controlled with water injection are given in Table 3.1-3. Table 3.1-4 presents trace element emission factors for distillate oil-fired turbines.

3.1.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF electronic bulletin board (919-541-5742), or on the new EFIG home page (<http://www.epa.gov/oar/oaqps/efig/>).

Supplement A, February 1996

- For the PM factors, a footnote was added to clarify that condensables and all PM from oil- and gas-fired turbines are considered PM-10.
- In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, 0.6 lb/10⁶ ft³ (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

- Text was revised and updated for the general section.
- Text was added regarding firing practices and process description.
- Text was revised and updated for emissions and controls.
- All factors for turbines with SCR-water injection control were corrected.
- The CO₂ factor was revised and a new set of N₂O factors were added.

Table 3.1-1. EMISSION FACTORS FOR LARGE UNCONTROLLED GAS TURBINES^a

Pollutant	EMISSION FACTOR RATING ^b	Natural Gas (SCC 2-01-002-01)		Fuel Oil (Distillate) (SCC 2-01-001-01)	
		Emission Factor ^c (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor ^c (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)
NO _x	C	3.53 E-03	0.44	5.60 E-03	0.698
CO	D	8.60 E-04	0.11	3.84 E-04	0.048
CO ₂ ^d	B	0.876	109	1.32	165
TOC (as methane)	D	1.92 E-04	0.024	1.37 E-04	0.017
SO _x (as SO ₂) ^e	B	7.52 E-03S	0.94S	8.09 E-03S	1.01S
PM-10					
Solids	E	1.54 E-04	0.0193	3.04 E-04	0.038
Condensables	E	1.81 E-04	0.0226	1.85 E-04	0.023
Sizing %					
<0.05 μm	D	15%	15%	16%	16%
<0.10 μm	D	40%	40%	48%	48%
<0.15 μm	D	63%	63%	72%	72%
<0.20 μm	D	78%	78%	85%	85%
<0.25 μm	D	89%	89%	93%	93%
<1 μm	D	100%	100%	100%	100%

^a References 2-3,8-11,13-18. SCC = Source Classification Code. PM-10 = particulate matter less than or equal to 10 μm aerodynamic diameter; sizing % is expressed in μm. Condensables are also PM-10 and all PM from oil and gas-fired turbines is less than 1μm in size and therefore are considered PM-10. To convert lb/hp-hr to g/kw-hr, multiply by 608. To convert from lb/MMBtu to ng/J, multiply by 430.

^b Ratings reflect limited data and/or a lack of documentation of test results; they may not apply to specific facilities or populations and should be used with care.

^c Calculated from lb/MMBtu assuming an average heat rate of 8,000 Btu/hp-hr.

^d Based on 99.5% conversion of fuel carbon to CO₂ for natural gas and 99% conversion for No. 2 oil.

^e All sulfur in the fuel is assumed to be converted to SO₂. S = % sulfur in fuel. For example, if sulfur content in the fuel is 3.4%, then S = 3.4. When sulfur content is not available, 0.6 lb/10⁶ ft³ (0.0006 lb/MMBtu) can be used; however, the equation is more accurate.

Table 3.1-2. EMISSION FACTORS FOR LARGE CONTROLLED GAS TURBINES^a
(SCC 2-01-002-01)

EMISSION FACTOR RATING: C

Pollutant	Water Injection (0.8 water/fuel ratio)		Steam Injection (1.2 water/fuel ratio)		Selective Catalytic Reduction (with water injection)
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/MMBtu) (fuel input)
NO _x	1.10 E-03	0.14	9.75 E-04	0.12	0.0088 ^b
CO	2.07 E-03	0.28	1.16 E-03	0.16	0.0084
N ₂ O ^c	2.00 E-05	0.003	2.00 E-05	0.003	ND
TOC (as methane)	ND	ND	ND	ND	0.014
NH ₃	ND	ND	ND	ND	0.0065
NMHC	ND	ND	ND	ND	0.0032
Formaldehyde ^d	ND	ND	ND	ND	0.0027

^a References 13,19-24. All data are averages of a limited number of tests and may not be typical of those reductions that can be achieved at a specific location. To convert from lb/hp-hr to g/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. NMHC = nonmethane hydrocarbons. ND = no data. SCC = Source Classification Code.

^b An SCR catalyst reduces NO_x by an average of 78%.

^c EMISSION FACTOR RATING: E. Based on limited source tests on a single turbine (Reference 5). Results may not be typical for all locations.

^d Hazardous air pollutant listed in the *Clean Air Act*.

Table 3.1-3. EMISSION FACTORS FOR DISTILLATE OIL-FIRED TURBINES
 CONTROLLED WITH WATER INJECTION^a
 (SCC 2-01-001-01)

EMISSION FACTOR RATING: E

Pollutant	Water Injection (0.8 water/fuel ratio)	
	Emission Factor ^b (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)
NO _x	2.31 E-03	0.290
CO	1.54 E-04	0.0192
TOC (as methane)	3.84 E-05	0.0048
SO _x ^c	— ^d	— ^d
PM-10 ^e	2.98 E-04	0.0372

^a Reference 25. To convert from lb/hp-hr to g/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. PM-10 = particulate matter ≤ 10 μm aerometric diameter. SCC = Source Classification Code.

^b Calculated from fuel input assuming an average heat rate of 8,000 Btu/hp-hr.

^c EMISSION FACTOR RATING: B

^d All sulfur in the fuel is assumed to be converted to SO_x.

^e All PM is ≤ 1 μm in size.

Table 3.1-4. TRACE ELEMENT EMISSION FACTORS FOR
DISTILLATE OIL-FIRED TURBINES^a
(SCC 2-01-001-01)

EMISSION FACTOR RATING: E^b

Trace Element	Emission Factor (lb/MMBtu)
Aluminum	1.5 E-04
Antimony ^c	2.2 E-05
Arsenic ^c	4.9 E-06
Barium	2.0 E-05
Beryllium ^c	3.3 E-07
Boron	6.5 E-05
Bromine	4.2 E-06
Cadmium ^c	4.2 E-06
Calcium	7.7 E-04
Chromium ^c	4.7 E-05
Cobalt ^c	9.1 E-06
Copper	1.3 E-03
Iron	6.0 E-04
Lead ^c	5.8 E-05
Magnesium	2.3 E-04
Manganese ^c	3.4 E-04
Mercury ^c	9.1 E-07
Molybdenum	8.4 E-06
Nickel ^c	1.2 E-03
Phosphorus ^c	3.0 E-04
Potassium	4.3 E-04
Selenium ^c	5.3 E-06
Silicon	1.3 E-03
Sodium	1.4 E-03
Tin	8.1 E-05
Vanadium	4.4 E-06
Zinc	6.8 E-04

^a Reference 2. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code.

^b Ratings reflect limited data; they may not apply to specific facilities or populations and should be used with care.

^c Hazardous air pollutant listed in the *Clean Air Act*.

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